Prevention of Significant Air Quality Deterioration Review

Final Determination

August 19, 2010

Facility Name: Mitchell Steam-Electric Generating Facility
City: Albany
County: Dougherty
AIRS Number: 04-13-09500002
Application Number: 18663
Date Application Received: December 18, 2008

State of Georgia
Department of Natural Resources
Environmental Protection Division
Air Protection Branch

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BACKGROUND

On December 18, 2008, Mitchell Steam-Electric Generating Plant (hereafter Plant Mitchell) submitted an application for an air quality permit to convert the Mitchell 3 coal-fired unit to a biomass-fired steam generating unit. The facility is located at 5200 Radium Springs Road in Albany, Dougherty County. The facility will add new biomass fuel handling, processing, storage, and delivery systems. After conversion, the biomass-fired unit will be able to generate 96 MW net at full load.

On February 11, 2010, the Division issued a Preliminary Determination stating that the modifications described in Application No. 18663 should be approved. The Preliminary Determination contained a draft Air Quality Permit for the construction and operation of the modified equipment.

The Division requested that Plant Mitchell place a public notice in a newspaper of general circulation in the area of the existing facility notifying the public of the proposed construction and providing the opportunity for written public comment. Such public notice was placed in the *Albany Herald* (legal organ for Dougherty County) on February 22, 2010. The public comment period expired on March 24, 2010.

During the comment period, comments were received from U.S. EPA Region IV, the facility and Greenlaw.

A copy of the final permit is included in Appendix A. A copy of written comments received during the public comment period is provided in Appendix B.

U.S. EPA REGION 4 COMMENTS

Comments were received from Gregg M. Worley, Chief, Air Permits Section, U.S. EPA Region 4, by letter on March 25, 2010. The comments are typed, verbatim, below and were the result of reviews by Katy Forney and Ana M. Oquendo of U.S. EPA Region 4.

Comments on the PSD Preliminary Determination

Comment 1

In EPA's previous comment letter dated October 1, 2009, we pointed out (see Comment 2 of the referenced letter) that the permitting authority should explain how they are addressing the PSD applicability for $PM_{2.5}$ while the State Implementation Plan (SIP) is being revised and approved. Georgia Environmental Protection Division (EPD) failed to provide such explanation.

EPD Response

In EPA's May 2008 Ruling, states with EPA-approved PSD programs, were authorized to continue to use the interim approach of relying on the PM_{10} Surrogate Policy for up to 3 years (May 2011), or until their revised SIPs are approved, whichever occurs first. The Division is relying on this PM_{10} Surrogate Policy as well as EPA's guide on $PM_{2.5}$ Modeling from March 2010.

The first modeling analysis submitted by Georgia Power demonstrated compliance with NAAQS, PSD Increment regulations, and GA's Toxics Air Pollutants regulations. Compliance with PM $_{2.5}$ NAAQS was at the time justified only by referencing the PM_{10} Surrogate Policy. However, in response to EPA's request that additional information be provided in order to demonstrate that compliance with PM_{10} NAAQS effectively guarantees that PM2.5 emissions will not result in an exceedance of the corresponding standard, GA Power performed the $PM_{2.5}$ emissions modeling per the attached document in Appendix C titled "Mitchell Biomass Project Air Quality Modeling Update $PM_{2.5}$ Modeling Analysis" dated June 22, 2010.

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The Division's modeling group prepared the memo to Renee Browne dated August 17, 2010 located in Appendix C, that addresses the review of the $PM_{2.5}$ modeling analysis submitted by the applicant in response to EPA's comments.

The air quality analyses reviewed and described in all sections of the memo referenced above show conformance of the project's PM2.5 impacts with the NAAQS. No Class I and Class II PSD Increment limits exist for this pollutant and therefore no such analyses were required.

Comment 2

In the previous EPA comment letter on the application for this facility, Comment 3, reads:
"… Region 4 finds that the application does not contain adequate rationale to support the use of PM_{10} surrogate approach to satisfy the PSD permit requirements for $PM_{2.5}$ (e.g., BACT and NAAQS compliance, for this project)."

The current PSD preliminary determination contains the rationale to demonstrate that PM_{10} is a reasonable surrogate for $PM_{2.5}$. However, the analysis does not address how that surrogacy relationship may be used to demonstrate that the source will not cause or contribute to a violation of the $PM_{2}.5$

National Ambient Air Quality Standards (NAAQS) in the affected area. The principal arguments for not considering a $PM_{2.5}$ analysis for the NAAQS compliance demonstration are "*limited data available on $PM_{2.5}$ emissions*" and that "*background concentrations of $PM_{2.5}$ are not well established.*" The permitting authority should either expand upon these broad statements to explain the technical difficulties of this particular situation that make $PM_{2.5}$ NAAQS compliance modeling infeasible or, alternatively, perform a $PM_{2.5}$ NAAQS compliance analysis following accepted procedures that include representative ambient background concentrations. To this end, we are in the process of developing guidance for performing an acceptable $PM_{2.5}$ source impact analysis. In the meantime, we are available to work with you to ensure that an acceptable analysis is developed for this project.

EPD Response

The last two paragraphs of page 28 and the first three paragraphs of page 29 of the PSD preliminary determination does expand on why there are technical difficulties of this particular situation that make $PM_{2.5}$ NAAQS compliance modeling infeasible. However, a memo dated March 23, 2010 from Stephen D. Page, Director of the Office of Air Quality Planning and Standards provides recommendations on two aspects of the modeling procedure for demonstrating compliance with the $PM_{2.5}$ NAAQS.

Based on EPA's comments on the $PM_{2.5}/PM_{10}$ surrogacy justification, the facility must supply additional information in order to demonstrate that the PM_{10} emissions allowed in the draft permit will not result in an exceedance in the $PM_{2.5}$ NAAQS of 15ug (annual) and 35 ug (24-hour).

To that end, EPD suggested that the facility pursue the following approach:

1) Determine the ratio of $PM_{2.5}$ to PM_{10} for: Stack emissions, road emissions, and wood chipper emissions, and include justification, and the estimated PM_{10} emissions rates to get a lb/hr for $PM_{2.5}$ for each of these.

2) If the model allows, determine the $PM_{2.5}$ impacts using the modeled PM_{10} contributions from the boiler stack, roads, and wood chipper scaled for $PM_{2.5}$. The one issue with this is that the model may not give contributions on the same day, but the highest from each source.

3) Apply projected project $PM_{2.5}$ to EPA's lowest proposed SIL – If the concentrations are significant further modeling is required. EPA defends use of this SIL because it is the worst proposed by EPA, and expected to be the final approved SIL shortly.

4) Contact EPD modeling group for Background Values.

GA Power performed the $PM_{2.5}$ emissions modeling per the attached document in Appendix C titled "Mitchell Biomass Project Air Quality Modeling Update $PM_{2.5}$ Modeling Analysis" dated June 22, 2010.

The results of the $PM_{2.5}$ modeling analysis show that maximum concentrations are above the lowest proposed SIL for the annual and 24-hour averaging periods. The maximum annual modeled concentration plus the ambient background concentration provided by the Division is below the annual NAAQS. Using the conservative Tier I approach and including the background concentration provided by the Division, the highest modeled concentration plus background is below the 24-hour NAAQS. Similarly, modeled concentrations are below the lowest proposed annual and 24-hour Class II PSD increments and below the lowest proposed 24-hour Class I SIL. The conservative analysis conducted to evaluate boiler start-up/shutdown operations shows that the highest modeled 24-hour average concentration plus background is below the NAAQS.

See the response to Comment 1, for the Division's review of the $PM_{2.5}$ modeling analysis submitted.

Comment 3

The Summary (p.i) and the Control Technology Review for the SG03 Biomass Steam Generating Unit – Background (pp.15, 17) mention the mechanical collector is planned to be located upstream of the electrostatic precipitator (ESP). However, the fact that the application stated two mechanical collectors were to be installed and the PSD preliminary determination only mentions one multiclone is misleading. The permitting authority should explain this inconsistency.

EPD Response

The PSD preliminary determination refers to the multiclone as a system (pages 5, 15, 25) and in some instances states "multiclones"(pages i, 8, 11,17, 22) and in one instance states the system consists of two multiclones (page 17). To clarify, the facility will be required to install a multiclone mechanical collector system (as listed in Table 4-10 of the preliminary determination) which will consist of two multiclones.

Comment 4

The Control Technology Review for the SG03 Biomass Steam Generating Unit – Background (p. 15) contains the list of all the control technologies to filterable PM_{10}. Nevertheless, it is not evident for the reader that the applicant already owns a cold-ESP and considered control technologies are limited to those that could be accommodated. The permitting authority should add a statement to the preliminary determination clarifying that emissions control technologies analyzed are limited due to the previous ownership of a cold-ESP.

EPD Response

On page 16 of the *Control Technology Review* for the SG03 Biomass Steam Generating Unit under Step 2, Eliminate Technically Infeasible Options, the first technology discussed is Wet ESP and it mentions that the facility has an existing ESP. Under the discussion for *COHPAC*, it is also mentioned that the facility has an existing ESP. However, it may not be evident in this section that it is a cold-ESP. However, the Division will add this clarification to page 15 as follows:

In considering these technologies, it should be noted that the facility has an existing cold-ESP and emissions control technologies analyzed are limited due to previous ownership of a cold-ESP.

Comment 5

Table 4-13 "Proposed BACT for Fugitive PM_{10} Emissions" in the PSD preliminary determination mentions that the emissions control methods for new paved roadways for biomass delivery are water flushing and lower vehicle travel speeds. However, Table 4-14 "BACT Summary for the Material Storage and Handling" dismissed lowering vehicle speeds as an emission control method for new paved roadways. The permitting authority should include the reasons for not choosing this control method as BACT in the EPD Review Section (p. 39).

EPD Response

The Division agrees, and lower vehicle traffic speeds should also be included in Table 4-14. The Table will be modified as follows:

Table 4-14: BACT Summary for the Material Storage and Handling

Pollutant	Control Technology	Proposed BACT Limit	Compliance Determination Method
PM_{10}	Water sprays for Unpaved Roadways for Potential Chipper Operations	None	Monitoring
PM_{10}	Lower Vehicle Traffic Speeds	None	Monitoring
PM_{10}	Partial Enclosures for the conveyors	None	Monitoring
PM_{10}	Partial Enclosures for the transfer points	None	Monitoring

Comment 6

On January 22, 2010, EPA signed a new NAAQS for nitrogen dioxide (NO_2). The new standard is a 1-hour standard set at the level of 100 parts per billion (ppb). The effective date of the new NAAQS is April 12, 2010. The EPD should evaluate its regulations to see if it is required to implement the new NAAQS as of April 12, 2010, should the permit not be issued prior to that date. If the EPD determines that the existing regulations provide for protection of any NAAQS in effect at the time of permit issuance (which would include the 1-hour NO_2 NAAQS beginning on April 12, 2010), then any permit issued on or after the effective date must contain a demonstration that the emissions increase from the proposed project does not cause or contribute to a violation of the new 1-hour NO_2 NAAQS.

EPD Response

The modification project will result in a decrease of 473 tpy of NOx emissions. Thus, this project does not trigger PSD for NOx, and modeling to determine compliance with the 1-hour NO_2 NAAQS is not required.

Comments on the PSD and Title V Permit Amendment

Comment 7

The citation used in Condition 3.3.5 could include a reference to Georgia rule 391-3-1-.02(2)(a)7 “Excess Emissions” as well.

EPD Response

The Division disagrees with this as Condition 3.3.5 is not about excess emissions as it defines operating loads. Condition 3.3.5 will remain as is.

Comment 8

Emission limitations for $PM_{2.5}$ should be identified. If EPA's PM_{10} surrogate policy is being used in this permit, then such limitations can be expressed in terms of PM_{10} emissions, where accompanied by the appropriate surrogacy demonstration.

EPD Response

PM_{10} emissions are being used as a surrogate for $PM_{2.5}$ emissions as requested by GA Power. Thus EPA's surrogate policy is being used in this permit. $PM_{2.5}$ emissions have been determined for the $PM_{2.5}$ modeling conducted by Georgia Power in the attached document titled "Mitchell Biomass Project Air Quality Modeling Update $PM_{2.5}$ Modeling Analysis" dated June 22, 2010 located in Appendix C.

Comment 9

The citation to Georgia rules (*i.e.,* 391-3-1-.02(3)(a)) used in Condition 4.1.5 seems not to be related to the requirements specified in the title V permit amendment. EPA recommends the permitting authority revise the citation and correct as needed.

EPD Response

The Division agrees and the citation should be Georgia State Rule 391-3-1-.02(6)(b)1. This correction has been made.

Comment 10

The citation on Condition 4.2.1.a (*i.e.,* 391-3-1-.02(2)(c)) should be revised by the permitting authority. The requirements set forth in the permit condition are about testing of PM_{10} on Steam Generating Unit 3. On the contrary, the cited Georgia rule is about incinerators.

EPD Response

The Division agrees and the correct citation should be Georgia State Rule 391-3-1-.03(2)(c). This correction has been made.

Comment 11

New Conditions 4.2.2 through 4.2.5 are citing 391-3-1-.02(2)(c) as well. This part of the rules is intended for incinerators, while the requirements stated are regulating a steam generating unit. By definition (391-3-1-.01(hh)), "incinerator" means all devices intended or used for the reduction or destruction of solid, liquid or gaseous waste by burning. EPA recommends the permitting authority revise and correct the citations accordingly.

EPD Response

The Division agrees and the correct citation should be Georgia State Rule 391-3-1-.03(2)(c). This correction has been made.

Comment 12

EPA believes the citation to 391-3-1-.02(6)(2)b1 found in Condition 5.2.10 and to 391-3-1-.02(6)(b)11(i) in Condition 5.2.14 have typographical errors. EPA requests the permitting authority revise and correct them as appropriate.

EPD Response

The Division agrees and the correct citation should be Georgia State Rule 391-3-1-.02(6)(b)1. This correction has been made.

Comment 13

Requirements, as stated, in Permit Condition No. 5.2.15 do not reflect the entire set of requirements contained in the cited regulation, 40 CFR 60.49b(d), which reads:

> "The owner or operator of an affected facility shall record and maintain records of the amounts of each fuel combusted **during each day** and calculate the annual capacity factor individually for…"

The permitting authority should include the daily recording of fuel usage into the referenced permit condition.

EPD Response

The Division has modified the Permit Condition to include the daily recording of fuel usage into the Permit Condition No. 5.2.15. It should be noted that Permit Condition No. 3.3.2 states that the Permittee shall comply with all applicable provisions of the "New Source Performance Standards" as found in 40 CFR 60, Subpart A-"General Provisions" and Subpart Db-"Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units" for the operation of Steam Generating Unit (Source Code: SG03).

Comment 14

The first paragraph in Condition 6.2.9 seems contradictory because it mentions reporting each *quarterly period* and at the end it mentions *semiannual period*. Please revised the wording and accuracy of the requirements and correct as needed.

EPD Response

The Division has modified the Permit Condition 6.2.9 to state "quarterly period" instead of "semiannual period".

Comment 15

The citation of 40 CFR 63.9(b)(4)(v) should be added in Condition 6.2.11 to support the requirement of providing the initial startup notification 15 days after the actual date.

EPD Response

The Division agrees and has added this citation to Permit Condition No. 6.2.11.

Comment 16

EPA suggests the permitting authority consider splitting Condition 6.2.15 into two parts since it covers two different aspects of the operation of the wood chipping unit. It will allow the permittee to distinguish between two different reporting requirements (*i.e.,* operating hours of the wood chipping unit and daily hours using the unpaved roadways associated to the same unit).

EPD Response

The Division agrees and has separated this Condition into two separate conditions. New Condition 6.2.20 will address daily hours using the unpaved roadways associated to the same wood chipping unit.

MITCHELL STEAM-ELECTRIC GENERATING PLANT COMMENTS

Comments were received from Ronald D. Just, Environmental Affairs Manager, Georgia Power, by email on March 22, 2010.

Comments on the PSD Preliminary Determination

Comment 1

Page 2, Table 1-3
The fluoride emissions increase should read "-282.2" instead of "-282.8".

EPD Response

The Division agrees and Table 1-3 is modified as requested.

Table 1-3: Emissions Increases from the Project

Pollutant	Baseline Years	Potential Emissions Increase (tpy)	PSD Significant Emission Rate (tpy)	Subject to PSD Review
PM	August 2006-July 2008	+164.6	25	**Yes**
PM_{10}	August 2006-July 2008	+164.6	15	**Yes**
$PM_{2.5}$	August 2006-July 2008	+164.6	10	**Yes**
VOC	August 2006-July 2008	+345.5	40	**Yes**
NO_X	August 2006-July 2008	-473.4	40	No
CO	August 2006-July 2008	+2530.0	100	**Yes**
SO_2	May 2006-July 2008	-1082.8	40	No
Pb	August 2006-July 2008	+0.264	0.6	No
Fluorides	August 2006-July 2008	-282.~~8~~2	3	No
SAM	May 2006-July 2008	-9.0	7	No

Comment 2

Page 2, 1st paragraph
Georgia Power would like to clarify that the baseline emissions were determined from the 5-year period immediately preceding the start of actual construction, not from the 5-year period immediately preceding the date a complete permit application was received by EPD.

EPD Response

The Division agrees as this is defined in the GA EPD Prevention of Significant Deterioration of Air Quality regulation 391-3-1-.02(7)2(i).

Comment 3

Page 4, Table 1-4
We suggest using column headings that more closely match the defined regulatory terms. The column heading "Past Actual" can be replaced by "Baseline Actual Emissions." The column heading "Future Actual" can be replaced by "Projected Actual Emissions/PTE."

EPD Response

The Division agrees and this information is modified as requested.

Table 1-4: Net Change in Emissions Due to the Major PSD Modification

Pollutant	Increase from Modified equipment		Associated Units Increase (tpy)	Total Increase (tpy)
	Baseline ~~Past~~ Actual Emissions	~~Future~~ Projected Actual Emissions/PTE		
PM/PM_{10}	72.2	236.8	-	+164.6
$PM_{2.5}$	72.2	236.8	-	+164.6
VOC	7.4	352.9	-	+345.5
NO_X	1929.1	1455.7	-	-473.4
CO	63.0	2593.0	-	+2530.0
SO_2	4884.2	3801.4	-	-1082.8
Pb	0.013	0.277	-	+0.264
Fluorides	282.2	0	-	-282.2
SAM	14.7	5.7	-	-9.0

Comment 4

Page 10, 1st paragraph
We suggest removing the sentence below to avoid confusion over the definitions noted in the 3rd paragraph on the same page. After the conversion, Mitchell Unit SG03 will use fuel oil as necessary (e.g. startup and shutdown), but during most operating conditions will be fired exclusively using biomass.

~~*The proposed biomass-fired steam generating unit (Source Code: SG03) is an EGU, as defined in 40 CFR 63.7575, since it does use fossil fuels.*~~

EPD Response

The comment is noted.

Comment 5

Page 11, Table 3-1
The footnote to the table, "During startup, biomass is 70% of load and oil is 30% of load," is not accurate and should be removed. As explained in the application, startup is initiated on fuel oil only. The ignitors will bring the boiler up to 30% of the boiler full load rating to achieve the desired boiler temperature. Once the boiler conditions are stabilized, biomass will begin to be injected in gradually increasing amounts while keeping oil firing steady. After achieving a minimum steady-state load, biomass injection will continue to increase and oil firing is proportionally decreased until the boiler is firing on 100% biomass at the minimum steady-state load. This ends the startup process. Because worst-case conditions during startup are presented in the table and used in our calculations and modeling, including a footnote is not necessary.

EPD Response

The comment is noted.

Comment 6

Page 13, 1st paragraph under CAIR
We suggest the following corrections and clarifications:

The Clean Air Interstate Rule regulations specified in Federal Rule 40 CFR 96 apply to the proposed ~~simple-cycle~~ biomass *electric generating unit because it has a nameplate capacity greater than 25 MW, it is fossil-fuel fired* according to CAIR definitions*, and it will supply electricity for sale, whether wholesale or retail.*

EPD Response

The Division agrees with the facility's comment. Simple cycle does not apply in this situation. Per 40 CFR 96.102, Fossil fuel-fired means, with regard to a unit, combusting any amount of fossil fuel in any calendar year.

Comment 7

Page 16, *Particle Agglomerator* paragraph
We suggest the following clarifications, consistent with the information submitted in the permit application:

"The particle agglomerator is not considered a technically feasible option for Unit 3. This technology has not been proven on biomass-fired sources ~~or coal-fired installations~~. For coal-fired installations, *~~T~~the results have been mixed. Furthermore, this technology is not proven for flue gas streams containing high levels of unburned carbon, such as those that might be experienced when burning certain wood fuel blends."*

EPD Response

The comment is noted.

Comment 8

Page 22, Table 4-6
The PM10 reduction in tons per year should be corrected for the following:

- COHPAC I with Lime Injection – PM10 reduction should be 166 instead of 161.
- WESP – PM10 reduction should be 161 instead of 158.
- WESP with Lime Injection – PM10 reduction should be 158 instead of 156.

While these small corrections do not have a material impact on results or conclusions, we suggest these corrections to ensure consistency with the information in Table 4-8.

EPD Response

The Division agrees and Table 4-6 is modified as requested.

Table 4-6 Average Cost Effectiveness of Control Options

Option	Description	Annualized Cost [$/yr]	PM_{10} Reduction [tpy]	Average Cost [$/ton]
1	COHPAC I with Lime Injection	$8,070,000	~~161~~166	$50,000
2	WESP	$5,880,000	~~158~~161	$37,300
3	COHPAC I	$7,520,000	160	$46,900
4	WESP with Lime Injection	$6,430,000	~~156~~158	$41,300
5	High Frequency Power Supply (Field #1, #2)	$25,000	58	$431
6	High Frequency Power Supply (Field #1)	$13,100	38	$348

Comment 9

Page 22, Table 4-7; Page 23, Table 4-8; Page 27, Table
The incremental cost in dollars per ton should be corrected for the following:

- COHPAC I with Lime Injection – incremental cost should be $438,000 instead of $569,000.
- WESP – incremental cost should be $56,800 instead of $58,700.
- High Frequency Power Supplies (Field #1, #2) – incremental cost should be $595 instead of $587.

These corrections again have no impact on the conclusions regarding cost effectiveness. However, the corrected numbers better match up with the cost and PM10 reduction numbers shown in these and other tables.

EPD Response

The Division agrees and Tables 4-7 and 4-8 are modified as requested.

Table 4-7 Incremental Cost Effectiveness of Dominant Upgrade Options

Option	Upgrade Option	Average Cost [$/ton]	Incremental Cost [$/ton]
1	COHPAC I with Lime Injection	$50,000	~~$569,000~~ $438,000
2	WESP	$37,300	~~$58,700~~ $56,800
5	High Frequency Power Supplies (Field #1, #2)	$431	~~$587~~ $595
6	High Frequency Power Supplies (Field #1)	$348	NA

Table 4-8 Summary of Top-Down BACT Impact Analysis Results for PM_{10} for Unit SG03

		PM_{10} Emissions		Economic Impacts				Energy Impacts	Environmental Impacts
Option	Description	Post-Retrofit Emissions [tpy]	Emissions Reduction [tpy]	Installed Capital Cost [$]	Total Annualized Cost [$/yr]	Average Cost Effectiveness [$/ton]	Incremental Cost Effectiveness [$/ton]	Incremental Increase over Baseline (kW)	Adverse Environmental Impact [Yes/No]
1	COHPAC I with Lime Injection	125	166	$44,500,000	$8,070,000	$50,000	$~~569,000~~ $438,000	1,130	Yes
2	WESP	129	161	$40,000,000	$5,880,000	$37,300	$~~58,700~~ $56,800	500	Yes
5	High Frequency Power Supply (Field #1, #2)	233	58	$190,000	$25,000	$431	$~~587~~ $595		No
6	High Frequency Power Supply (Field #1)	253	38	$100,000	$13,100	$348	NA		No

Comment 10

Page 22, last paragraph
The installation of multiclones was considered a part of the base project design. We suggest the following clarifications:

"BACT for PM10 has been determined to include ~~*be installation of the multiclones and*~~ *upgrading the existing ESP to install new high frequency power supplies on the first two fields (Field #1 and Field #2) of the eight total fields* and operation of the multiclones that will be installed as part of the baseline for the project*."*

EPD Response

The Division agrees with the facility's comment.

Comment 11

Page 32, 5th paragraph
We suggest clarifying in this paragraph that the facility has an existing cold-side ESP and that the BACT analysis relies on upgrades to that cold-side ESP. Suggested revisions follow.

"In the remainder of Section 4.2.3, the facility discusses why a CO oxidation catalyst is not technically feasible for Plant Mitchell. The Division asked the permit applicant to provide more justification why a carbon monoxide catalyst following a Hot Side ESP is not feasible for the Mitchell Biomass Project. The

facility has an existing cold-side ESP and plans to make upgrades to the cold-side ESP to implement BACT for the biomass project. *Georgia Power provided justification* for why conversion of the existing equipment to or installation of a hot-side ESP is not a feasible option *in an information package dated on November 12, 2009, located in Appendix B."*

EPD Response

The Division agrees with the facility's comment.

Comment 12

Page 36, Selection of VOC BACT
The preliminary determination notes that *"GA Power proposes BACT for VOC to be best combustion practices and the VOC BACT limit of 0.05 lb/mmBtu on a 3 hour average."* We would like to clarify that our application proposed a VOC BACT limit of 0.05 lb/mmBtu, based on a **3-run performance test**. Because VOC is not monitored continuously, EPD should also note in the preliminary determination that compliance with the VOC emission limit is demonstrated on a continuous basis through compliance with the CO emission limit. The CO emission limit is based on a 30-day rolling average, not a three hour average.

EPD Response

The Division agrees with this comment and the changes are made as follows:

From the facility's analysis and a review of the EPA RACT/BACT/LAER Clearinghouse (RBLC) and other sources of information, GA Power proposes BACT for VOC to be best combustion practices and the VOC BACT limit of 0.05 lb/mmBtu on a ~~3 hour average~~ 3 run performance test. Since VOC is not continuously monitored, and CO is monitored continuously, compliance with the 30-day rolling CO limit will also demonstrate compliance with the VOC limit.

Comment 13

Page 46, Paragraph under *Hours of Operation Recordkeeping for the Wood Chipping Unit*
We suggest the following changes to more closely track regulatory language applicable to the potential wood chipping unit. The term "non-resettable hour meter" is used in the applicable New Source Performance Standard (NSPS) regulation and is an accepted term.

Condition No. 5.2.14 requires the installation, operation and maintenance of a non-resettable hour meter ~~*continuous monitoring system (or device)*~~ *for the Wood Chipping Unit (Source Code: WC03) to track the hours of operation to show compliance with Condition No. 3.3.13.*

EPD Response

The Division agrees with the facility's comment.

Comment 14

Page 48, 2nd paragraph
We would like to clarify that the section of the application that discusses the air quality analysis requirements, methodologies, and results is titled Air Quality Impacts Analysis, not *Air Quality Dispersion Report.*

EPD Response

The Division agrees with this comment and the changes are made as follows:

The proposed project at the Plant Mitchell triggers PSD review for PM_{10}, CO and VOC. An air quality analysis was conducted to demonstrate the facility's compliance with the NAAQS and PSD Increment standards for PM_{10} and CO. An additional analysis was conducted to demonstrate compliance with the Georgia air toxics program. This section of the application discusses the air quality analysis requirements, methodologies, and results. Supporting documentation may be found in the ~~Air Quality Dispersion Report~~ Air Quality Impacts Analysis of the application and in the additional information packages.

Comment 15

Page 55, Paragraph under *Growth*
We would like to clarify that while the preliminary determination indicates that "no significant related industrial, commercial or residential growth is expected to accompany this project," we actually expect the project to bring many benefits to the local area in terms of jobs and businesses. Construction of the project will require as many as 190 workers. Biomass suppliers and related industry may also add between 50 and 75 permanent new jobs related to harvesting, processing, and transporting the biomass to the Mitchell facility. However, as we note in the application, these economic benefits are not expected to result in growth-related air pollution impacts from the project.

EPD Response

This comment is noted.

Comment 16

Page 56, 2nd paragraph under *Selection of Toxic Air Pollutants for Modeling*
We would like to clarify that, as noted in Section 2.5 of the application, AP-42 emission factors were used for estimating hazardous air pollutant emissions, except for mercury and hydrogen chloride, which were based on fuel analysis.

EPD Response

The Division agrees with this comment and the changes are made as follows:

The permitted facility discharges to the atmosphere thirty nine hazardous air pollutants (HAPs) shown in Table IX of the EPD modeling memo dated November 9, 2009 included in Appendix C as emitted from the biomass boiler and the wood chipper. Emission rates were estimated using the AP-42 emission factors, except for mercury and hydrogen chloride, which were based on fuel analysis, at the operating conditions (fuel load) that yield the worst emission rates.

Comment 17

Page 58, under *Section 3.0: Requirements for Emission Units*
Statements made in the preliminary determination about Conditions 3.2.5 and 3.3.10 are not completely consistent with actual permit language (See Comment #19). Please also note that the BACT limit in Condition 3.3.10 does not account for emissions for fuel oil firing during startup. During fuel oil firing, we note that, as stated in our application, the PM10 emissions are estimated at 0.05 lb/MMBtu during oil-firing, instead of 0.04 lb/MMBtu.

EPD Response

The Division will modify Permit Condition 3.2.5 as suggested and thus this will be consistent with what is stated for this condition. Condition 3.3.10 will not be modified as it is a PSD condition and this limit applies during startup, shutdown and/or malfunction. Compliance with this condition is done through a performance test which will be performed at normal operating conditions.

Comments on the PSD and Title V Permit Amendment

Comment 18

Condition 3.2.4. This Condition specifies that the wood biomass used as fuel should be "free of foreign material." We note that some managed forests, which are a likely source of biomass supply for Mitchell and other biomass-fueled facilities, may use herbicides in their forest management practices, especially after harvesting and before replanting. This application typically occurs once every 25 years and is more common for pine trees than hardwoods. To put in place a practical standard and to be consistent with nationally recognized standards, we suggest that EPD include a diminimis exemption similar to the Green-e Energy standard requirements. Green-e states that "[q]ualified wood fuels may contain de minimis quantities (less than 1% of total wood fuel) of the … excluded contaminates." See page 3 of the Green-e Energy National Standard Version 1.6, available at http://www.green-e.org/docs/energy/Appendix%20D_Green-e%20Energy%20National%20Standard.pdf.

EPD Response

The Division disagrees in part as 1% is an accurate percentage and it would be necessary to show compliance with 1%. The Division notes that biomass may contain de minimus quantities and will specify that the biomass shall be free of post harvest pesticides.

Comment 19

Condition 3.2.5. This Condition specifies that the ESP and multiclone should "to the extent practicable" be operated during all periods, including startup, shutdown, and malfunction. We would like to clarify that while the multiclone can be operated safely during oil-firing (e.g. during startup), the ESP must be carefully brought online during these periods for safety reasons and for preservation of the equipment. During a large portion of startup, the unit will be fired with oil. Carry-over of oil into the ESP can cause concerns over sparking. Oil carry-over may also foul the plates in the ESP, reducing the equipment's ability to clean the plates. Thus, it is standard practice to wait until biomass fuel is introduced into the boiler before energizing large portions of the ESP. We note that the PM limit in Condition 3.3.3 referenced by this Condition excludes periods of startup, shutdown, and malfunction. Operating all equipment in a manner consistent with good air pollution control practices for minimizing emissions is already covered by existing Condition 8.17.1, so that language does not need to be repeated here. We suggest the following revisions.

Upon completion of this modification project, in order to comply with Condition No. 3.3.3, ~~at all times, including startup, shutdown and malfunction,~~ the Permittee shall ~~to the extent practicable,~~ maintain and operate the ~~Steam Generating Unit (Source Code: SG03) including~~ the associated Dry Electrostatic Precipitator (APCD ID No. EP03) and the Multiclone (APCD ID No. MC03) ~~in a manner consistent with good air pollution control practice for minimizing emissions~~ at all times that the Steam Generating Unit (Source Code: SG03) is operating, except during startup, shutdown and malfunction.

EPD Response

The Division agrees, and the changes have been made.

Comment 20

Condition 3.3.5. We suggest clarifying the definition of startup in this Condition. Startup and shutdown are processes over a period of time over a range of loads and should not be defined by one specific load. Also, including the "net" load in the Condition is not relevant and not necessary. The Condition uses our estimate of the difference between gross and net load at full capacity (105 MW gross, 96 MW net) to estimate the gross and net load at minimum load. This is not necessarily accurate. The net load has no bearing on emissions and the facility is motivated to minimize station service requirements to reduce costs. We suggest the following revisions.

For the purposes of this Permit: The following operating loads are defined for the Steam Generating Unit (Source Code: SG03):
[40 CFR 52.21(j)]

a. Minimum Operational Load: Source SG03 operating at 65 megawatts (MW) gross ~~(56 MW net)~~.

b. Startup and Shutdown Load: Source SG03 operating at any load less than 65~~32~~ *megawatts (MW) gross ~~(29 MW net)~~. Startup load shall last no longer than 17 hours from initial firing, with a once a year exception of startup load lasting no longer than 24 hours during boil~~er~~* out of the superheater, until the unit reaches minimum *~~up~~ operational load.*

EPD Response

The Division agrees, and the changes have been made.

Comment 21

Condition 3.3.6. The operational limit included in this Condition should include exceptions for startup, shutdown, and malfunction. For practical enforcement, the limit should be triggered by a specific time period (e.g. three hours). Condition 6.1.7 can also be revised to include reporting for deviations from the operational and time limit. Suggested revisions follow.

Upon completion of this modification project, the Permittee shall not operate the Steam Generating Unit (Source Code: SG03) at a load lower than the minimum operational load as defined in Permit Condition 3.3.5 for more than three hours, except during startup, shutdown, and malfunction.

EPD Response

The Division partially agrees but suggests that the time period be for two consecutive hours instead of three hours.

Comment 22

Condition 3.3.8. Similar to PM_{10}, compliance with the VOC emission limit is demonstrated by a performance test, which is required to be performed during periods that do **not** include startup, shutdown, and malfunction. Including the startup, shutdown, and malfunction language in this Condition causes confusion over how the performance test should be conducted. Also, as noted in previous comments on the preliminary determination, compliance with the VOC emission limit is demonstrated through compliance with the CO emission limit, which is based on a 30-day rolling average, not a three hour average. While the CO emission limit does cover periods of startup, shutdown, and malfunction, the averaging time is not consistent with the VOC limit specified in this Condition. We suggest the following revisions.

Upon completion of this modification project, the Permittee shall not cause, let, suffer, permit or allow the emission of volatile organic compounds (VOCs) from the Steam Generating Unit (Source Code: SG03) in amounts equal to or exceeding 0.05 pounds per million Btu (lbs/10^6 Btu) as demonstrated by a performance test *~~for a three hour average. The emission limit in this permit condition shall apply during all times of operation, including startup, shutdown, and malfunction.~~*

EPD Response

The Division partially agrees. Compliance with the VOC limit is demonstrated via the performance test required in Condition 4.2.5. The VOC limit still applies during startup, shutdown and malfunction. Thus, Condition 3.3.8 is modified as follows:

3.3.8 Upon completion of this modification project, the Permittee shall not cause, let, suffer, permit or allow the emission of volatile organic compounds (VOCs) from the Steam Generating Unit (Source Code: SG03) in amounts equal to or exceeding 0.05 pounds per million Btu (lbs/10^6 Btu). The emission limit in this permit condition shall apply during all times of operation, including startup, shutdown, and malfunction.
[40 CFR 52.21(j)]

Comment 23

Condition 3.3.10. We suggest clarifying this Condition to show that compliance is demonstrated through a performance test (See Comment #5). We suggest the following revisions.

Upon completion of this modification project, the Permittee shall not cause, let, suffer, permit or allow the emission of total particulate matter less than 10 micrometers in diameter (PM10) from the Steam Generating Unit (Source Code: SG03) in amounts equal to or exceeding 0.04 pounds per million Btu (lbs/10^6Btu) ~~for a three hour average~~ as demonstrated by a performance test.

EPD Response

The Division partially agrees. Compliance with the PM_{10} limit is demonstrated via the performance test required in Condition 4.2.1. Thus, Condition 3.3.10 is modified as follows:

3.3.10 Upon completion of this modification project, the Permittee shall not cause, let, suffer, permit or allow the emission of total particulate matter less than 10 micrometers in diameter (PM_{10}) from the Steam Generating Unit (Source Code: SG03) in amounts equal to or exceeding 0.04 pounds per million Btu (lbs/10^6Btu).
[40 CFR 52.21; 40 CFR 60.43b(h)(1) subsumed and 391-3-1-.02(2)(d) subsumed]

Comment 24

Condition 3.4.6. For clarity, please specify the averaging time (3-hour) in this Condition.

EPD Response

The Division will not add this clarification. The facility has a NOx CEMS to determine compliance for any time period while firing fuel oil. The Procedure for Testing and Monitoring of Sources of Air Pollutants for Fuel Burning Sources defines an excess emission for sources using a CEMS to show compliance with a standard as the average of three contiguous one hour periods in which the value exceeds the limit. GA State Rules reference these Procedures for general monitoring requirements.

Comment 25

Condition 4.1.3. We suggest revisions shown below to allow flexibility for using new, updated, and improved methods that may be developed in the future.

Minor changes in methodology may be specified or approved by the Director or his designee when necessitated by process variables, changes in facility design, or improvement or corrections that, in his opinion, render those methods or procedures, or portions thereof, more reliable. <u>The permittee may also, upon obtaining written approval from the Division, use alternate methods that are deemed to be more appropriate.</u>

EPD Response

The Division does not agree with the wording change in this condition. Prior to conducting any performance tests, the facility is required to submit a testing plan per the Division's Procedures for Testing and Monitoring Sources of Air Pollutants (PTM). The Division can approve any alternate methods, if deemed appropriate, at this time.

Comment 26

Condition 4.2.1(b). There is a typo in the units for minimum sampling volume. "Feed" should be replaced with "feet." We also note that if testing of total particulate matter shows emissions less than the PM_{10} limit, there should be no need to test for PM_{10} specifically. The Condition should allow that flexibility.

EPD Response

The Division has corrected this typo. The Division agrees with the flexibility not to test for PM_{10} if total particulate matter shows emissions less than the PM_{10} limit.

b. Within 60 days after achieving maximum operating rate, but no more than 180 days after initial startup, the Permittee shall conduct initial performance tests for particulate matter and opacity as required by 40 CFR 60.46b(d) to show compliance with Condition 3.3.3. The sampling time for each run shall be at least 120 minutes and the minimum sampling volume shall be 60 dry standard cubic fee~~d~~t (dscf). The temperature of the sample gas in the probe and filter holder shall be monitored and maintained at 320 ± 25 ^{o}F.
[40 CFR 60.46b(d)]

Comment 27

Conditions 4.2.2, 4.2.3, 4.2.4, and 4.2.5. The regulatory citation to 391-3-1-.02(2)(c), the Georgia Rule for Incinerators, for each of these conditions appears to be in error. We also suggest using the term "maximum production rate," which more closely matches regulatory terminology, instead of "maximum steam generation rate" or "maximum operating rate."

EPD Response

The correct citation should be [391-3-1-.02(3) and 391-3-1-.03(2)(c)]. The Division has also made the changes as requested.

Comment 28

Conditions 4.2.2, 5.2.10(a) and (b), 6.1.7(c)(i), 6.2.10. Condition 5.2.13 requires that we submit a Compliance Assurance Monitoring (CAM) plan 180 days after initial startup for multiclone and/or ESP control of particulate matter (PM). Until the CAM testing and plan are complete, we cannot determine the best way to monitor compliance with the PM limits. Including Conditions 4.2.2, 5.2.10(a) and (b), 6.1.7(c)(u), and 6.2.10 in the permit before the CAM plan is complete is premature. We also note that the facility will continue to use a continuous opacity monitor after the conversion. We suggest removing these permit conditions and incorporating requirements later after submittal of the CAM plan. The data required by Condition 4.2.2 is always included in PM test reports, so it need not be specified again here. Similar to what we have done with previous projects, we will use the CAM testing to help us determine the best parameters to monitor for ESP performance, thus Conditions 5.2.10(a) and 6.2.10 are also not necessary at this time. The proper excursion level for ESP power or other parameters cannot be determined before the CAM testing is complete; thus, 6.1.7(c)(i) should also be removed. Condition 6.2.10 specifies an equation for determining ESP power level using voltage and current data from the first and second fields. We note that the ESP actually has eight fields. We will install high frequency power supplies on two fields. Using only the first two fields to calculate ESP power will not represent the overall power level of the ESP.

EPD Response

The Division partially agrees. The testing, monitoring, and recordkeeping and reporting requirements are current Georgia state requirements for wood-fired boilers with ESPs. The facility can suggest to the Division alternate monitoring parameters after CAM testing is performed. Condition 6.2.10 has been modified to reflect an ESP with eight fields as follows:

6.2.10 The Permittee, using the hourly records of total secondary voltage and secondary current for each field of the electrostatic precipitator (APCD ID No. EP03) that are obtained in accordance with Condition 5.2.10, shall determine and record total secondary power for each field of the electrostatic precipitator (APCD ID No. EP03) in accordance with the following equation: [391-3-1-.02(6)(b)1 and 40 CFR 70.6(a)(3)(i)]

$$P_T = \sum_{n=1}^{8} Vn * In$$

Where:

P_T = Total secondary power to the electrostatic precipitator (APCD ID No. EP03), in Watts

V_n = Total secondary voltage of each field of the electrostatic precipitator (APCD ID No. EP03), in kilovolts

I_n = Total secondary current of the each field of the electrostatic precipitator (APCD ID No EP03), in milliamps

Comment 29

Condition 4.2.3. As currently written, this Condition could require the facility to certify the CO CEMS within 30 days of reaching maximum load in order to complete the 30-day performance test within 60 days of achieving maximum production rate. We request a more feasible deadline that the facility must <u>initiate</u> the 30-day test within 60 days of achieving maximum production rate. We suggest the following revisions.

Within 60 days after achieving <u>the</u> maximum <u>production</u> ~~steam generation~~ rate at which the facility will be operated, but not later than 180 days after initial startup of the facility, the Permittee shall <u>initiate</u> ~~conduct~~ a performance evaluation using the continuous emissions monitoring system (CEMS) for monitoring CO required by Condition 5.2.1.b. For the initial compliance evaluation, CO from the steam generating unit is monitored for 30 successive steam generating unit operating days and the 30-day average emission rate is used to determine compliance with the CO emission limit in Condition 3.3.9

EPD Response

The Division partially agrees. The Division has changed the reference to maximum steam generation to maximum production, see Comment 27. The Division will leave the word "conduct" in the condition.

Comment 30

Condition 4.2.4. As noted in our application, after the conversion to biomass, Plant Mitchell expects to remain a major source of hazardous air pollutants (HAPs). Our permit application and modeling are based on the emissions estimates that indicate the biomass facility will be major. As EPD notes in the preliminary determination, EPA has not yet promulgated new rules requiring maximum achievable control technology (MACT) for Industrial/Commercial/Institutional Boilers and Process Heaters. Furthermore, EPA has not yet issued guidance on implementing Section 112(j) of the Clean Air Act for this source category. We suggest that setting testing requirements in Condition 4.2.4 for certain HAPs is premature. When the MACT rule is issued, we intend to comply with the requirements for major sources and suggest amending the permit at that time.

EPD Response

The Division agrees and Condition No. 4.2.5 will be renumbered as Condition No. 4.2.4.

Comment 31

Condition 5.2.14. We suggest using the term "non-resettable hour meter," which matches language used in the applicable NSPS for the potential wood chipper, instead of "non-resettable continuous monitoring system (or device)."

EPD Response

The Division has made this change as follows:

5.2.14 The Permittee shall install, calibrate, maintain, and operate a ~~non-resettable continuous monitoring system (or device)~~ <u>non-resettable hour meter</u> for the Wood Chipping Unit 3 (Source Code: WC03) to track the hours of operation. The Permittee shall maintain documentation that demonstrates the reason the engine was in operation (normal operation, maintenance, or testing). The system shall meet the applicable performance specification(s) of the Division's monitoring requirements.
[391-3-1-.02(6)(b)1]

Comment 32

Conditions 5.2.15. It is not possible to distinguish how much of each type of biomass was burned for a specified period of time. Biomass delivered to the plant will be unloaded to one of two storage piles. These piles will contain a mix of all the biomass delivered to the site. As an alternative, we can record the amount and type, as defined by Condition 3.2.4, of biomass received on a monthly basis.

The Permittee shall measure and record the amount and type of the ~~wood~~ biomass fuel <u>received</u> *~~burned in Steam Generating Unit (Source Code: SG03)~~ on a monthly basis, as well as calculate the total amount of fuel burned on a monthly basis.*

EPD Response

The Division partially agrees and the change has been made to include both monthly and daily recordkeeping as required by NSPS Subpart Db -"Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units".

Comment 33

Condition 5.2.16(a). To clarify the requirements, we recommend separating this Condition into two, one for monitoring fuel oil, and one for monitoring biomass. Also, Section 12.5.2 in Method 19 is written for coal and oil, and the sampling methods specified are not appropriate for biomass. Sampling of biomass will be conducted manually. We recommend using the following additional condition and revisions to the draft Condition shown below.

Condition 1

For each shipment of ultra low sulfur diesel fuel, biodiesel, or biodiesel blends received, the Permittee shall obtain from the supplier a statement certifying that the oil complies with the specifications of ultra low sulfur diesel contained in ASTM D 975 and/or biodiesel contained in ASTM D 6751. As an alternative to the procedure described above, the Permittee may, for each shipment of ultra low sulfur diesel fuel, biodiesel, or biodiesel blends received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D 4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures of Test Method ASTM D 129, ASTM D 1552 or by some other test method approved by the US EPA and acceptable to the Division.

Condition 2

The Permittee shall obtain fuel quality certification for ~~ultra low sulfur fuel oil, ultra low sulfur fuel oil/biodiesel blend, and~~ biomass suppliers to include sulfur content, ash content, heat content, and moisture content~~, as applicable~~. If such certification cannot be obtained, the Permittee shall conduct initial and periodic fuel sampling and analysis of the uncertified fuel. The samples shall be ~~acquired and~~ analyzed using the procedures of Section 12.5.2 in Method 19 of the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The Permittee may use Test Method ASTM D5142 for determining moisture content of the biomass sample in lieu of the methods specified in Method 19. Such periodic fuel sampling shall be conducted daily *as fired or weekly* as received *at a minimum. Sampling shall be analyzed for moisture content, ash content, fuel heat content, and fuel sulfur content.*

EPD Response

The Division agrees with this comment and has made the change as follows:

5.2.16 The Permittee shall monitor the fuel quality of each of the fuels combusted in the wood-fired Steam Generating Unit (Source Code: SG03) by the following methods:
[391-3-1-.02(6)(b)1]

a. For each shipment of ultra low sulfur diesel fuel, biodiesel, or biodiesel blends received, the Permittee shall obtain from the supplier a statement certifying that the oil complies with the specifications of ultra low sulfur diesel contained in ASTM D 975 and/or biodiesel contained in ASTM D 6751. As an alternative to the procedure described above, the Permittee may, for each shipment of ultra low sulfur diesel fuel, biodiesel, or biodiesel blends received, obtain a sample for analysis of the sulfur content. The procedures of ASTM D 4057 shall be used to acquire the sample. Sulfur content shall be determined using the procedures of Test Method ASTM D 129, ASTM D 1552 or by some other test method approved by the US EPA and acceptable to the Division.

b. The Permittee shall obtain fuel quality certification from ultra low sulfur fuel oil, ultra low sulfur fuel oil/biodiesel blend, and biomass suppliers to include sulfur content, ash content, heat content, and moisture content, as applicable. If such certification cannot be obtained, the Permittee shall conduct initial and periodic fuel sampling and analysis of the uncertified fuel. The samples shall be acquired and analyzed using the procedures of Section 12.5.2 in Method 19 of the Division's Procedures for Testing and Monitoring Sources of Air Pollutants. The Permittee may use Test Method ASTM D5142 for determining moisture content of the biomass sample in lieu of the methods specified in Method 19. Such periodic fuel sampling shall be conducted daily as fired or weekly as received at a minimum.

Sampling shall be analyzed for moisture content, ash content, fuel heat content, and fuel sulfur content.

c. The Permittee shall develop and maintain fuel-handling practices as specified by the Steam Generating Unit (Source Code: SG03) manufacturer to encourage complete combustion, and make them available for review at the Division's request.

In addition, the Division will add New Condition 6.2.21 to further address fuel certification and recordkeeping.

6.2.21 The Permittee shall verify that each shipment of biomass, as defined in Condition No. 3.2.4.c and 3.2.4.d, except for forestry residues as defined in Condition No. 3.2.4.b, received for combustion in the boiler (Source Code: SG03) complies with the requirements of Condition 3.2.4. Verification shall consist of fuel receipts obtained from the fuel supplier certifying that the fuel is clean untreated wood. The Permittee shall retain records on site for a period of at least five years in a format suitable for inspection.
[391-3-1-.02(6)(b)1 and 391-3-1-.03(2)(c)]

Comment 34

Condition 5.2.16(c). Other than fuel size recommendation, the boiler manufacturer is unlikely to provide recommendations related to fuel handling. The facility will develop internal procedures for biomass handling and operation.

EPD Response

The Division agrees and has modified Condition 5.2.16 to allow for this provision.

Comment 35

Condition 6.1.7(a). The definition for excess emissions should be corrected with the following addition. *Any six-minute period during which the average opacity, as measured by the COMS for Steam Generating Unit 3 (Source Code: SG03) equals or exceeds twenty (20) percent*, except for one six-minute period per hour of not more than 27 percent.

EPD Response

The Division agrees with this comment and the changes are made.

Comment 36

Condition 6.1.7(b). Please specify in (iii) and (iv) of this Condition that these apply to only the steam generating unit with Source Code SG03.

EPD Response

The Division agrees and has added the following changes to Condition 6.1.7(b):

iii. Any time the 30-day rolling average for CO, exceeds 0.45 lb/mmBtu from the Steam Generating Unit (Source Code: SG03).

iv. Any 3-hour averaging period that the NOx limit, exceeds 0.3 lb/mmBtu of heat input derived from liquid fossil fuel fired in the Steam Generating Unit (Source Code: SG03).

Comment 37

Condition 6.2.8. This Condition should only require the detailed malfunction records for events that are associated with excess emissions. We suggest the following revisions.

The Permittee shall maintain records of the occurrence and duration of any startup or *shutdown, ~~or malfunction~~ in the operation of steam generating unit (Source code: SG03) and the wood chipping unit (Source Code: WC03), ~~any malfunction of the air pollution control equipment~~ or any periods during which a continuous monitoring system or monitoring device is inoperative. Said records shall be retained by the Permittee for at least five years ~~after the date of any such startup, malfunction, or measurement~~.* The Permittee shall maintain records of the occurrence and duration of any malfunction in the operation of the steam generating unit (Source Code: SG03), the wood chipping unit (Source Code: WC03), or any air pollution control equipment that results in excess emissions.

EPD Response

The Division disagrees and will require the detailed records for any malfunction whether excess emissions are created or not. Therefore, no change will be made to Condition 6.2.8.

Comment 38

Condition 6.2.12. Please clarify in this Condition what is required for recording the "type" of startup. We note that the permit only differentiates between a normal startup and the once per year exception for startup following a superheater boil out.

EPD Response

The Division agrees that it is not required to state the type of startup, and Condition 6.2.12 is modified as follows:

6.2.12 The Permittee shall maintain the following records as they relate to the startup and shutdown of the steam generating unit (Source code: SG03):
[391-3-1-.02(6)(b)(1) and 40 CFR 52.21]

a. ~~The type of startup initiated, per day;~~ The hours attributed to the startup, and the hours attributed to shutdown. If the steam generating unit (Source code: SG03) was not in operation on any given day, the records shall so note.

b. Identify startup of the pollution control systems – Electrostatic Precipitator (APCD ID No. EP03).

Comment 39

Condition 6.2.14. If all operating limits required of the wood chipping unit are met, it is neither necessary nor practical to record the reason the unit was in operation on a monthly basis. During a given month, a unit may be operated for multiple reasons (e.g. testing, maintenance, normal operation). The information recorded by the hour meter will not differentiate between these reasons. We suggest the following revisions.

The Permittee shall maintain monthly records of the operation of the wood chipping unit (Source code: WC03) that are recorded through the non-resettable hour meter required in Condition No. 5.2.14. ~~*The Permittee shall record the time of operation of the unit and the reason the unit was in operation during that time*~~*. Records shall be maintained for a period of five (5) years in a format suitable for inspection by or submission to the Division.*

EPD Response

The wood chipper has a 3000 hours for 12 consecutive months limit. There is no requirement in NSPS IIII to record the reason for the type of operation. The Division agrees with this comment and has made the change as noted.

Comment 40

Condition 6.2.17. This condition is duplicative of Condition 5.2.16(a) and can be removed without relaxing or changing the amount of recordkeeping required of the facility.

EPD Response

Condition 6.2.17 discusses the recordkeeping requirements while Condition 5.2.16(b) discusses what records need to be obtained. Yet some of the information is duplicative. Condition 6.1.1 of Permit No. 4911-095-0002-V-02-0 requires that all records required to be maintained by this Permit shall be recorded in a permanent form suitable for inspection and submission to the Division and to the EPA. The records shall be retained for at least five years following the date of entry. Given this Condition 6.1.1 and Condition 5.2.16(b), Condition 6.2.17 can be deleted. The Division will also add the word “maintain” in addition to “obtain” records in Condition 5.2.16(b).

GREENLAW COMMENTS

Comments were received from Ela Orenstein, on March 24, 2010 on behalf of Georgians for Smart Energy, Southern Alliance for Clean Energy, Friends of the Chattahoochee and Flint Riverkeeper.

Comment 1

The wood chipper and biomass handling system are subject to the requirements of 40 CFR 52.21 because they emit PM, PM_{10}, and PM $_{2.5}$ and the modification is significant for these NSR – regulated pollutants.

Page i, "Summary", of the Preliminary Determination states that "PM/PM_{10} , $PM_{2.5}$, CO and VOC emissions increases were above the PSD significant level thresholds." Yet, Table 3.1.1 does not indicate that 40 CFR 52.21, "Prevention of Significant Deterioration" and GAQC 391-3-1-.02(7) are "Applicable Requirements/Standards" for the wood chipper and the biomass handling system. Moreover the preliminary determination and the draft permit provide no review of a top-down analysis and no BACT limit for wood shavings (particulate emissions) from the wood chipper.

EPD Response.

The Division will add citations for 40 CFR 52.21 in Table 3.1.1 for the wood chipper and biomass handling system. Condition 3.3.13 contains a BACT limit of 3000 hrs during any twelve consecutive months for the wood chipper engine operation. Condition 3.3.7 limits the work day of not more than 12 hours per day for unpaved roadway sources associated with wood chipping operations.

A BACT analysis was done for the wood chipper diesel engine and from fugitives associated with the wood chipping operation for PM_{10} emissions. A BACT Analysis was done as part of the Biomass Delivery, Storage and Handling in Section 4 of the Preliminary Determination. Also see Table 4-13 of the Preliminary Determination for the Proposed BACT for fugitive PM_{10} Emissions. The PM_{10} BACT limit for the Diesel Engine was determined to be 0.4 grams per kilowatts-hour, which is the same limit as in 40 CFR 60 Subpart IIII. Please refer to the preliminary determination for details.

Appendix C of the application, titled "Fugitive PM Emissions Calculations", contain the fugitive PM calculations associated with the Potential On-Site Wood Chipping Operations. These Emissions have several sources, "UR 01 Unpaved Roadways", "WC03 Wood Chipper", and "CV02 Wood Chipper Conveyors and Drop Points". Page C-10 for PM_{10} Emissions from the Wood Chipper, namely dropping of logs onto the chipper and the dropping of wood chips into the hopper, indicates emissions of PM_{10} to be 1.99E-2 tpy. The total PM_{10} Emissions from the Potential On-Site Wood Chipping Operations is 4.43 tpy.

Fugitive PM_{10} Emissions and BACT limits associated with the wood chipping operations were also included in the modeling.

Comment 2

The wood chipper (Emission Unit ID No. WC03 is not a fugitive emission source and is not subject to GAAQC Rule 391-3-1-.02(2)(n), but is subject to GAQC Rule 391-3-1-.02(2)(b) and (e).

Table 3.1.1, Applicable Requirements/Standards should be corrected and a condition should be added limiting wood particulate from the wood chipper to less than or equal to:

(i) $E = 3.59P^{0.62}$ for process input weight rate up to and including 30 tons per hour;

Or

(ii) $E = 17.31P^{0.16}$ for process input weight rate in excess of 30 tons per hour;

And

20% opacity.

EPD Response.

Georgia Rule (n) applies to any operation, process, handling, transportation or storage at a facility. This rule requires the facility to take reasonable precautions to prevent fugitive emissions from becoming airborne and limits opacity to 20 percent from fugitive dust sources. The wood chipper itself is not subject to Rule (n) but fugitive emissions from the wood chipping operations are subject to the Rule (n) limit.

Also, the wood chipper is not subject to Georgia Rule (e) as it does not meet the definition of a manufacturing process.

The Division will add the citation for Georgia Rule (b) in Table 3.1.1 for the wood chipper.

Comment 3

Conditions referring to "completion of this modification project" are not practically enforceable as written.

The draft permit consistently makes reference to compliance beginning "upon completion of this modification project; however the draft permit does not define what constitutes "completion of the modification project," does not require a report of the "completion of the modification project" and completion of the project, which may not be synonymous with startup, may conflict with applicable requirements for which compliance is required at startup. The draft permit needs to be corrected to define "completion of the modification project," to require a report to the Division of the "completion of the modification project," and to ensure that "completion of the modification project" is on or before "startup," or assign a specific and appropriate compliance deadline if compliance cannot be demonstrated before startup.

EPD Response.

The Division will modify Condition 6.2.11 as follows to include the definition of "upon completion of this modification":

6.2.11 The Permittee shall provide all notifications as required per 40 CFR 60.7 and 40 CFR 63.9 by the dates specified. Specifically, the Permittee shall provide notifications of the actual date of initial startup of Steam Generating Unit (Source Code: SG03) and wood chipping unit (Source Code: WC03) postmarked within 15 day after such date. For purpose of this permit, "upon completion of the modification" is defined as initial startup of Steam Generating Unit (Source Code: SG03). [391-3-1-.02(6)(b)(1)]

Comment 4

The carbon monoxide (CO) limit for the steam generating unit (SG03) is not low enough and is not the limit associated with the Best Achievable Control Technology (BACT) as required under 40 CFR 52.21(j) and GAQC 391-3-1-.02(7).

A review of the RACT/BACT/LAER Clearinghouse indicates that there are at least thirteen determinations in which CO limits are a biomass-fired boiler are lower than 0.45 lb/MMBtu on a 30-day rolling average or shorter averaging period. One of these limits is being attained using oxidation catalysts and Georgia Power and GA EPD has indicated that the exit temperature from the boiler would be too low to achieve a 75% efficiency using catalyst. Summit Energy Yellow Pine and Biomass Energy South Point Biomass Station have indicated that they could achieve a 50% or lower control efficiency using oxidation catalyst even at a lower-than-ideal inlet temperatures to the catalyst. While lower inlet temperatures result in a lower control efficiencies, they do not render oxidation catalyst technically infeasible because there is some efficiency still associated with this application. Therefore like Yellow Pine, Georgia Power and GA EPD must justify why oxidation catalyst is prohibitive from a economic, energy, or environmental impact analysis.

Georgia Power then cited incompatibility with the existing hot-side ESP as their reasoning for rejecting oxidation catalysts. Although the least effective and least expensive upgrade to their existing system to control PM10 was selected for this project, there are many more efficient PM controls available that would be compatible with an oxidation catalyst. BACT does not allow the elimination of a control option for one pollutant due to incompatibility with an existing control for another pollutant, for which BACT is also required, simply to avoid costs.

Furthermore , several similar facilities are attaining lower emission limits with no add on control, but simply by using “good combustion practices”. At least three of these more stringent determinations were made by the GA EPD Air Protection Branch for Yellow Pine Permit No. 4911-061-0001-P-01-0, Tri Gen BioPower Permit No. 2631-039-0025-P-01-1 and Temple Inland Permit No. 2631-115-0021-V-01-4.

Regardless of the regulatory driver for meeting these limits (BACT, MACT, SIP, etc.), they are achievable in practice. The minimum acceptable CO limit should be 0.10 lb/MMBtu on a 12-month rolling average for loads greater than 50% and no more than 0.24 lb/MMBtu on a 24-hr rolling average. No 30-day rolling average should be greater than 0.149 lb/MMBtu.

EPD Response.

These facilities were included in the BACT Analysis Spreadsheet located in Appendix D of the Preliminary Determination. Page 31 of the preliminary determination states that the exhaust gas temperature after the PM_{10} controls at the facility is expected to be between 320 ^{o}F and 380 ^{o}F. These temperatures are well below the optimum catalyst operating temperature range (700 ^{o}F – 1,100 ^{o}F) and are even below the point at which virtually no emission reductions are expected (380 ^{o}F).

Summit Energy Yellow Pine had a 1529 MMBtu/hr Bubbling Fluidized Boiler (BFB) in their original Application No. 17700. The facility was issued Permit No. 4911-061-0001-P-01-0 on May 15, 2009. In Application No. 19518 dated March 4, 2010, Yellow Pine proposes to construct a Circulating Fluidized Bed (CFB) Boiler with a heat input capacity of 1,425 MMBtu/hr. This boiler was furnished with a Selective Non-Catalytic Reduction System to reduce NOx, not a catalytic oxidizer to reduce CO. The application states a reduction in the total potential NOx emissions by 35%, mainly due to the change in technology from a BFB Boiler to a CFB boiler. The Yellow Pine application stated that catalytic oxidation was technically infeasible for reduction of CO emissions citing that catalytic oxidation has not been demonstrated and is not commercially available for use on fluidized bed boilers. In addition, catalytic oxidation is not listed as a control for CO emissions from fluidized bed boilers in the RBLC database.

Biomass Energy South Point Biomass Station indicated in their Permit Application, BACT Analysis, Revision 5, dated September 23, 2004, that the oxidation catalysts can operate within the temperature range of 400 ^{o}F to 1,000 ^{o}F. The facility stated that a catalytic oxidation for South Point Power is able to achieve a 50% reduction of CO resulting in CO emission of less than 0.1 lb/MM Btu at 318 MMBtu/hr for each of the seven stoker boilers. The rolling twelve-month average CO limit is 139.28 tons per year. This facility is subject to Non-attainment NSR and LAER (Lowest Achievable Emission Rate). However, the facility has not completed construction or performed any testing, so the actual effectiveness of the catalyst is not yet known.

It should be noted that these boilers will be newly constructed and are 24% of the capacity of Plant Mitchell's proposed modified stoker boiler. The smaller boilers are brand new, while the Plant Mitchell boiler is about 10 years old and is a modified coal-fired unit to a stoker grate wood-fired unit. Thus the emissions limits are not comparable for the boiler units. Plant Mitchell is also not required to meet LAER limits.

In section 4.2.3 of the permit application, and in an information package dated on November 12, 2009, located in Appendix B of the preliminary determination, the facility provided further justification why oxidation catalyst is technically inf easible for reduction of CO emissions. Therefore it is not necessary to demonstrate why the use of catalyst oxidation is prohibitive from an economic, energy, or environmental impact analysis.

As noted in the information package dated on November 12, 2009, located in Appendix B of the preliminary determination, the facility has an existing cold-side ESP, not a hot-side ESP. The facility was required to provided justification for considering the installation of a carbon monoxide (CO) catalyst following a hot-side ESP as part of the BACT analysis. This justification can be found in the previously mentioned document.

Given that the existing cold-side ESP with upgrades to two fields and the multiclone system are needed to meet the PM_{10} BACT limit, the addition of a new hot-side ESP is still not technically feasible as explained in the previously mentioned document due to the use of sodium conditioning agents and catalyst poisoning.

There is a LAER limit of 0.24 lb/MMBtu on a 24 hour average for the Fibrominn Biomass Power Plant. This is a Greenfield facility with a vibrating grate, spreader stoker boiler, that is 60% of the capacity of the Plant Mitchell Boiler. Plant Mitchell is not required to meet LAER limits.

There is a BACT limit of 0.149 lb/MMBtu for the Yellow Pine facility. This is a Greenfield facility with a Bubbling Bed Fluidized Boiler (BFB) that is larger in size to the Plant Mitchell stoker wood-fired boiler. The Bubbling Bed Fluidized Boiler is not the same technology as a stoker wood-fired boiler and the technologies are not comparable for setting CO emissions limits.

Also, please refer to Item No. 3 of the document titled "Response to Questions from the May 21, 2009 Email from EPD to GPC on the Mitchell Biomass Conversion Project" located in Appendix B of the Preliminary Determination, for justification on the uniqueness of the Plant Mitchell Project as it relates to emission limits. Therefore, the Division believes CO BACT is good combustion controls and a limit of

0.45 lb/MMBtu (30 day rolling average). Please refer to pages 31 to 34 in the Preliminary Determination for CO BACT details.

Comment 5

The PM_{10} limit on the steam generating unit (SG03) is not representative of BACT.

The GA EPD has limited the boiler to 0.04 lb/MMBtu on a 3-hour average for PM $_{10}$. However, there are numerous determinations for similar sources that are less than this limit. The following table lists a few:

Facility	Pollutant	Limit (lb/MMBtu)	Averaging Period	Control Device
Sappi Cloquett, LLC	$PM_{2.5}$	0.031	3-hour	995 using MultiCyclone ESP
Koda Energy, Boiler #1 and #3	PM	0.03, 0.037	Unknown	Cyclone/ESP

The proposed permit allows Georgia Power to merely upgrade process controls on an old, existing electrostatic precipitator. The upgraded process control option is not BACT. As such, the permit allows for out-dated controls in lieu of requiring BACT controls.

Georgia EPD did not evaluate a baghouse for control of particulates from the unit. The particulate matter from biomass fired boilers are typically less than 2.5 microns in diameter and baghouses are quite effective in removing fine particulate matter. A baghouse has been required as BACT on the San Joaquin Solar biomass facility.

Even existing electrostatic precipitators, such as the one used to attain BACT for the Simpson Tacoma Kraft Co., LLC's biomass boiler can achieve a 0.02 lb/MMBtu limit on a calendar day average (24-hour).

Therefore, at the very least GA EPD must establish a more stringent limit for PM_{10} on a longer averaging hour to meet the standards set by other BACT determinations.

EPD Response

These facilities were included in the BACT Analysis Spreadsheet located in Appendix D of the Preliminary Determination. Also, please refer to Item No. 3 of the document titled "Response to Questions from the May 21, 2009 Email from EPD to GPC on the Mitchell Biomass Conversion Project" located in Appendix B of the Preliminary Determination, for justification on the uniqueness of the Plant Mitchell Project as it relates to emission limits.

As stated on Page 30 of the Preliminary Determination, the Sappi Cloquett, LLC facility has a $PM_{2.5}$ BACT Limit of 13.5 lb/hr for a 3-hour average. This limit is derived from PM_{10} test result of 1.6 lbs/hr a value much lower than the permit limit of 30 lbs/hr. Due to the uncertainty in $PM_{2.5}$ test methods, a more conservative value of 13.5 lbs/hr was set for the $PM_{2.5}$ BACT limit. This is an existing unit that was modified by adding NOx controls. The boiler is much smaller at 33% of the capacity of the Plant Mitchell wood-fired boiler.

The BACT limits for Koda Energy Biomass Boiler 1 and Biomass Boiler 3 are as stated in the table above and the EPA RBLC Database at 0.0300 lb/mmBtu and 0.037 <u>when firing biomass</u>. The combined capacity is 23% of the capacity of the Plant Mitchell wood-fired boiler.

BACT for the biomass boilers at the Sappi Cloquett, LLC and Koda Energy facilities was determined to be an existing Multiclone and ESP combination, similar to the BACT controls for Plant Mitchell, which were upgrades to an existing cold-side ESP and installation of a multiclone system upstream of the air pre-heater prior to the ESP. Yet the limits differ due to the uniqueness of the Mitchell project as referenced previously and also the boilers are not of comparable size.

As stated in Section 4.3.2 of the application and page 24 of the preliminary determination, the proposed permit also includes the installation of a multiclone system that has an efficiency of 70% and is located upstream of the air pre-heater prior to the ESP that has an efficiency of greater than 99%. Both pollution control equipment are required to meet the PM_{10} BACT limit. This represents an overall efficiency of 99.7% for filterable PM. Further justification for the limit of 0.04 lb/MMBtu is also provided on page 24 of the Preliminary Determination.

A baghouse for control of particulates from the unit was evaluated. In section 4.0 of the Preliminary Determination, Control Technology Review for PM_{10} emissions, the COHPAC technology which consists of installing a fabric filter is included as one of the technologies to be evaluated. COHPAC I requires the installation of a fabric filter in a separate casing downstream of the existing ESP. COHPAC II is a retrofit of the outlet field of an existing ESP with a fabric filter. Only COHPAC I is commercially available and therefore COHPAC II is technically infeasible. COHPAC I is considered technically feasible.

In Table 4-2 on page 19 of the Preliminary Determination, COHPAC I is rated no. 3 in control effectiveness, with an overall collection efficiency of 55%. For further details on the overall control efficiency, refer to page 19 of the Preliminary Determination. Refer to Section 4.3.6 of the application for the energy, environmental and economic impacts of the COHPAC control technology. The average cost effectiveness for the COHPAC control technology was $46,900/ton. This ranked 3rd of the control options evaluated. The COHPAC control option was not deemed cost effective and fell outside the least-cost envelope, eliminating this technology from further consideration.

Simpson Tacoma Kraft Co., LLC was included in the BACT Analysis Spreadsheet located in Appendix D of the Preliminary Determination and in Table 4-16 of the application. The facility has a PM_{10} filterable limit of 0.02 lb/MMBtu. Plant Mitchell's BACT limit of 0.04 lb/MMBtu <u>total</u> PM_{10} includes condensables and filterable PM_{10}, while Simpson's PM_{10} BACT limit does not. Also the Simpson boiler size is 45% the capacity of the wood-fired boiler at Plant Mitchell.

GA EPD agrees that given the uniqueness of this project, as defined in Item No. 3 of the document titled "Response to Questions from the May 21, 2009 Email from EPD to GPC on the Mitchell Biomass Conversion Project" located in Appendix B, Plant Mitchell's BACT limit of 0.04 lb/MMBtu <u>total</u> PM_{10} (including condensables and filterable PM_{10}) is reasonable. This takes into account the BACT controls of a multiclone system, and upgrades to an existing cold-side ESP. For further details, see Item 5 of the document titled "Response to Questions from the May 21, 2009 Email from EPD to GPC on the Mitchell Biomass Conversion Project" located in Appendix B.

Initial and annual PM_{10} testing will be sufficient to demonstrate compliance with the 0.04 lb/MMBtu PM_{10} BACT limit. No additional PM_{10} limits are necessary.

Comment 6

While it may be true that the PM_{10} control options for the biomass-fired boiler have some level of control efficiency for $PM_{2.5}$, at least one BACT determination establishes a limit for $PM_{2.5}$ from wood-fired boilers and GA EPD must establish a limit in the permit for $PM_{2.5}$.

Page i, "Summary", of the Preliminary Determination establishes that the significance threshold for $PM_{2.5}$ exists and is exceeded by the new biomass-fired boiler at Georgia Power Plant Mitchell. However, the permit fails to establish an emission limitation for $PM_{2.5}$. Since a BACT determination exists that limits $PM_{2.5}$ specifically, to a level that is lower than that established for PM_{10} in this permit, the surrogacy policy cannot be used to assume that the draft PM_{10} limit represents BACT for $PM_{2.5}$ as well. GA EPD must explicitly establish a $PM_{2.5}$ limit for the boiler and the $PM_{2.5}$ limit should be no greater than 0.032 lb/MMBtu per calendar day. Regardless of EPD's PM_{10}/ $PM_{2.5}$ surrogacy arguments, this change is a major modification for $PM_{2.5}$ and, as such, a BACT determination for $PM_{2.5}$ must be done.

EPD Response

The facility is using PM_{10} emissions as a surrogate to estimate $PM_{2.5}$ emissions, and a separate BACT limit of $PM_{2.5}$ aside from PM_{10} is not required. Please refer to the discussion on $PM_{2.5}$ in the preliminary determination (pages 26 to 30).

Comment 7

The VOC limit on the biomass-fired boiler is not representative of BACT.

Georgia EPD has established a VOC limit from the biomass boiler of 0.05 lb/MMBtu on a 3-hr average. However, there are BACT determinations, even without the use of oxidation catalysts, that are more stringent than the draft limit for Plant Mitchell. For instance, Sierra Pacific Energy's wood-fired cogeneration boiler is limited to 0.019 lb/MMBtu on a 1-hour average, which is much shorter that the averaging period for Plant Mitchell's proposed boiler.

EPD Response

The Division's review of the wood fired boiler for Sierra Pacific Energy shows that this unit is rated at 430 mmBtu/hr with a 30 MW plant output. This unit is about one third the size of the Plant Mitchell boiler output, and thus these two units are not comparable.

Plant Mitchell will comply with the VOC BACT limit of 0.05 lbs/mmBtu via initial and annual performance tests. Please refer to the discussion on VOC BACT in the preliminary determination.

Comment 8

A Proper and Complete Determination of PSD Applicability Needs to be Completed and Supported.

The Preliminary Determination for the Plant Mitchell permit states that there will be a decrease in SO_2 and NOx emissions at the unit once the unit switches from coal to biomass. Preliminary Determination at 1. However, the Preliminary Determination does not provide the details to support this claim.

The permit allows use of fuel oil or biodiesel not just for startup and shutdown but also "to assist in achieving peak load and flame stabilization." Draft Permit Condition 3.2.4.a. It is not clear that GA EPD took this condition which allows co-firing of fuel oil and biodiesel into account in projecting whether there would be any emission increases in SO_2 or NOx resulting from this permit modification. The maximum amount of the highest emitting fuels must be considered in determining if this fuel change will result in a significant emission increase of either SO_2 or NOx.

Further it appears that only emissions during normal source operation were included in determining if a significant emission increase of SO_2 or NOx would occur as a result of this modification. Preliminary Determination at 2-3. However, the analysis of emissions following the modification, whether based on "projected actual emissions" or "potential to emit," must include emissions from startups, shutdowns, and malfunctions and must be based on the maximum emissions rates. It does not appear that such an analysis has been done properly for this modification.

If a proper determination of emission increases from the project shows that a significant emission increase of either NOx or SO_2 could occur, then a determination of net emissions increase for SO_2 and NOx needs to be done.

EPD Response

An analysis showing decreases in SO_2 and NOx emissions due to this modification is in Section 3.2 of the permit application. This modification will decrease 473 tpy of NOx emissions and decrease 1083 tpy of SO_2 emissions. The facility used a 24 Month Baseline Period of May 2006 through April 2008 for SO_2 and H_2SO_4. The facility used a 24 Month Baseline Period of August 2006 through July 2008, for NOx, PM/PM_{10}, CO, VOC, lead (Pb) and fluoride (F). For the baseline actual emissions calculations, the SO_2 and NOx data was taken from continuous emissions monitoring systems (CEMS). For further details on the emissions calculations for all other NSR pollutants, see pages 3-1 and 3-2 of the permit application.

The facility did account for worst-case emissions during startup and shutdown for SO_2 and NO_X emissions while firing fuel oil or biodiesel fuel. Please refer to Section 2.0, Pages 2-7 to 2-9 in the permit application.

The facility is authorized to fire ultra low sulfur No.2 fuel oil and biodiesel fuel during startup and shutdown or only to achieve peak load stabilization. Four oil fired ignitors will be installed to facilitate startup of the boiler for biomass operation and assist in achieving peak load and flame stabilization. These ignitors are sized to bring the boiler up to <u>30%</u> of the boiler's full capacity, this input is sufficient to achieve the operating temperature of the superheater and turbine. Biomass is not injected <u>until</u> stable boiler conditions are reached, after approximately <u>twelve hours</u>. Biomass is slowly injected until the combined heat input from the biomass and ignitors totals about <u>63%</u> of the boiler's full capacity, after about <u>three hours</u>, while maintaining the maximum heat input from the oil burners. For the next <u>two hours</u>, biomass injection is increased and oil firing is proportionally decreased on a heat input basis until the boiler is firing on 100 percent biomass at the minimum steady-state load heat input. Cold startup lasts <u>seventeen hours</u> and warm startup lasts <u>thirteen hours</u> (initial boiler heating only takes about <u>eight hours</u>).

The applicant states that after discussion with potential vendors, this method of startup, provides for a more precisely controlled startup sequence and provides for lower emissions during startup. Table 2-2 of the application compares worst case startup rates with steady state loads. The hourly mass comparison indicates that steady state hourly mass rates are the worst case. For SO_2 emissions, steady state full load is 3.4 times the start-up hourly mass rate. For NO_2 emissions, steady state full load is 1.7 times the start-up hourly mass rate. The emission factors for NOx and SO_2 were based on an Alstom Power Inc. (Alstom, the original equipment manufacturer for the existing Mitchell 3 boiler) study performed for three loads points (full, intermediate, and medium).

Using the;

- Worst case mass hourly rates for NOx and SO_2
- 24 Month Baseline Period of May 2006 through April 2008 for SO_2
- 24 Month Baseline Period of August 2006 through July 2008, for NOx,

SO_2 and NOx show decreases of – 1082.8 tpy and –473.4 tpy as indicated in Table 3-1 of the application.

Comment 9

Enforceability Comments

a. The permit must include appropriate limitations consistent with the air modeling that was done. For example, the permit fails to identify a heat input capacity limitation for the boiler yet, according to the Preliminary Determination, a maximum heat input capacity was relied on to determine emissions from the modification.

EPD Response

The maximum heat input capacity for Plant Mitchell's biomass boiler is confidential yet is considered a Large Industrial Sized Boiler (>250 mmBtu/hr) according to EPA's RBLC database. There is no federal or state regulations that require setting a permit limit for the heat input capacity of the boiler. PSD and Georgia air quality regulations require that a facility be built as specified in the application.

b. Regarding the types of fuels burned, the permit should include a limit on the amount of fuel oil and biodiesel fuel burned. Otherwise, it appears this permit allows for co-firing with fuel oil and/or biodiesel with biomass, and yet proper the PSD applicability analysis did not account for this as discussed above.

EPD Response

The facility only fires ultra low sulfur No. 2 fuel oil and biodiesel fuel during startup and shutdown or only to achieve peak load stabilization. See the description of fuel oil usage and startup versus steady state emission comparisons in the response to Comment 8 above.

c. Further, Permit Condition 3.2.4.d improperly allows the EPD the discretion to approve the burning of other untreated biomass other than the fuels listed in this condition. Because the level of pollutants emitted can vary greatly in the type of biomass burned, EPD cannot allow such a change in the permit to be done administratively. Any change in the biomass burned must be subject to a PSD applicability review and potentially an air modeling analysis.

EPD Response

Condition 3.2.4.d requires the facility to submit a sample analysis and to seek written approval from the Division prior to firing any untreated biomass that does not meet the definition in Condition 3.2.4. This request will allow the Division to determine if this untreated biomass will qualify under the definition of biomass in Condition 3.2.4. If not, the facility shall be required to submit an application for a permit modification.

d. While the permit only allows for the use of untreated biomass, the permit should specifically prohibit the burning of construction and/or demolition waste, municipal solid waste, and tires, as these materials can be high in toxic emissions.

EPD Response

Permit Condition 3.2.4 only allows the facility to fire biomass in the boiler (fuel oil and biodiesel fuel can be fired during startup, shutdown and for flame stabilization). This condition does not authorize the facility to fire construction or demolition waste, municipal solid waste and/or tires. No additional condition is necessary prohibiting the use of such material.

e. Although the permit only allows untreated biomass to be burned, the permit does not include any monitoring, recordkeeping, or reporting conditions to ensure that only untreated biomass is burned.

EPD Response

To ensure compliance with Condition 3.2.4, the Division will require the facility to obtain fuel supplier certification for the clean untreated wood. New Condition 6.2.21 is added as follows:

6.2.21 The Permittee shall verify that each shipment of biomass, as defined in Condition No. 3.2.4.c and 3.2.4.d, except for forestry residues as defined in Condition No. 3.2.4.b, received for combustion in the boiler (Source Code: SG03) complies with the requirements of Condition 3.2.4. Verification shall consist of fuel receipts obtained from the fuel supplier certifying that the fuel is clean untreated wood. The Permittee shall retain records on site for a period of at least five years in a format suitable for inspection.
[391-3-1-.02(6)(b)1 and 391-3-1-.03(2)(c)]

f. Condition 6.1.7.b.i improperly allows too high of a sulfur content of fuel oil to be considered an exceedance. Specifically, this condition states any time the unit fires fuel that is greater than 3% sulfur by weight, it is an exceedance. Yet Condition 3.2.4.a specifies that only ultra low sulfur fuel oil, less than 0.0015% sulfur, can be used in the boiler. Therefore, Condition 6.1.7.b.i must be changed accordingly; otherwise it allows an exceedance of the limitation of Condition 3.2.4.a.

EPD Response

Existing Condition 6.1.7.b.i reports any exceedance of the 3 percent sulfur limit in Georgia Rule (g) for any fuel burned in the boiler and/or the combustion turbines.

The Division will add Condition 6.1.7.b.vii as follows to report any exceedance if any fuel oil is burned with greater than 0.0015 percent sulfur limit:

6.1.7.b.vii. Any time that the Permittee fires fuel oil in the steam generating unit (Source Code: SG03) that contains greater than 0.0015 percent sulfur, by weight.

g. The permit fails to require PM_{10} continuous emission monitoring (CEMS) to ensure compliance with the PM_{10} BACT limit. Use of a CEMS is the only way to assure continuous compliance with the PM_{10} BACT limit, which must be met at all times including startup and shutdown. Further, given that the PM_{10} emissions can vary with the different types of biomass allowed to be burned at Plant Mitchell, infrequent stack testing is wholly inadequate to ensure compliance with the PM_{10} BACT limit. Therefore a PM_{10} CEMS must be required.

EPD Response

Initial and annual PM_{10} testing will be sufficient to demonstrate compliance with the PM_{10} BACT limit.

h. The permit appears to drop a requirement for an SO_2 CEMS. The SO_2 CEMS should continue to be required, especially given that the unit will be allowed to burn fuel oil and biodiesel.

EPD Response

No SO_2 CEMS requirement was explicitly listed in the previous permits. The facility has installed a SO_2 CEMS on Steam Generating Unit (Source Code: SG03) since it is subject to the Acid Rain Program. The SO_2 CEMS requirement will be added to Condition 5.2.1d for completeness. Condition 5.2.1d is modified as follows:

5.2.1d A Continuous Emissions Monitoring System (CEMS) for the measurement of sulfur dioxide (SO_2) emissions from the Steam Generating Unit (Source Code: SG03). The SO_2 emission rate shall be recorded in pounds per million Btu heat input.

EPD CHANGES

The Division will correct a typo in Condition No. 3.3.10 to reflect that the PM_{10} limit of 0.04 pounds per million Btu includes both filterable and condensable particulate matter from the Steam Generating Unit (Source Code: SG03). Condition 3.3.10 is modified as follows:

3.3.10 Upon completion of this modification project, the Permittee shall not cause, let, suffer, permit or allow the emission of <u>total</u> particulate matter less than 10 micrometers in diameter (PM_{10}) from the Steam Generating Unit (Source Code: SG03) in amounts equal to or exceeding 0.04 pounds per million Btu (lbs/10^6Btu).
[40 CFR 52.21; 40 CFR 60.43b(h)(1) subsumed and 391-3-1-.02(2)(d) subsumed]

APPENDIX A

AIR QUALITY PERMIT

4911-095-0002-V-02-3

APPENDIX B

WRITTEN COMMENTS RECEIVED DURING COMMENT PERIOD

APPENDIX C

Additional Information

Mitchell Biomass Project, Air Quality Modeling Update, PM2.5 Modeling Analysis dated June 22, 2010

GA EPD APB Modeling Memo to Renee Browne dated August 17, 2010